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TRANSMITTAL LETTER TO THE UNITED STATES DESIGNATED/ELECTED OFFICE (DO/EO/US) CONCERNING A FILING UNDER 35 U.S.C. 371

ATTORNEY'S DOCKET NUMBER: US57.0326-WO

U.S. APPLICATION NO. (If known, see 37 CFR 1.5): 09/936863

INTERNATIONAL APPLICATION NO.	INTERNATIONAL FILING DATE	PRIORITY DATE CLAIMED
PCT/GB00/01074	21 March 2000 (21.03.00)	22 March 1999 (22.03.99)

TITLE OF INVENTION
METHOD AND SYSTEM FOR REDUCING EFFECTS OF SEA SURFACE GHOST CONTAMINATION IN SEISMIC DATA

APPLICANT(S) FOR DO/EO/US
ROBERTSSON, Johan Olof Anders, KRAGH, Julian Edward, MARTIN, James Edward

Applicant herewith submits to the United States Designated/Elected Office (DO/EO/US) the following items and other information:

1. ☒ This is a **FIRST** submission of items concerning a filing under 35 U.S.C. 371.
2. ☐ This is a **SECOND** or **SUBSEQUENT** submission of items concerning a filing under 35 U.S.C. 371.
3. ☐ This is an express request to begin national examination procedures (35 U.S.C. 371(f)). The submission must include items (5), (6), (9) and (21) indicated below.
4. ☒ The US has been elected by the expiration of 19 months from the priority date (Article 31).
5. ☒ A copy of the International application as filed (35 U.S.C. 371(c)(2))
   - a. ☐ is attached hereto (required only if not communicated by the International Bureau).
   - b. ☒ has been communicated by the International Bureau.
   - c. ☐ is not required, as the application was filed in the United States Receiving Office (RO/US).
6. ☐ An English language translation of the International Application as filed (35 U.S.C. 371(C)(2)).
   - a. ☐ is attached hereto.
   - b. ☐ has been previously submitted under 35 U.S.C. 154(d)(4).
7. ☐ Amendments to the claims of the International Application under PCT Article 19 (35 U.S.C. 371(c)(3)).
   - a. ☐ are attached hereto (required only if not communicated by the International Bureau).
   - b. ☐ have been communicated by the International Bureau.
   - c. ☐ have not been made; however, the time limit for making such amendments has NOT expired.
   - d. ☐ have not been made and will not be made.
8. ☐ An English language translation of the amendments to the claims under PCT Article 19 (35 U.S.C. 371 (c)(3)).
9. ☐ An oath or declaration of the inventor(s) (35 U.S.C. 371(c)(4)).
10. ☐ An English language translation of the annexes of the International Preliminary Examination Report under PCT Article 36 (35 U.S.C. 371(c)(5)).

Items 11 to 20 below concern document(s) or information included:

11. ☐ An Information Disclosure Statement under 37 CFR 1.97 and 1.98.
12. ☐ An assignment document for recording. A separate cover sheet in compliance with 37 CFR 3.28 and 3.31 is included.
13. ☐ A FIRST preliminary amendment.
14. ☐ A SECOND or SUBSEQUENT preliminary amendment.
15. ☐ A substitute specification.
16. ☐ A change of power of attorney and/or address letter.
17. ☐ A computer-readable form of the sequence listing in accordance with PCT Rule 13ter.2 and 35 U.S.C. 1.821-1.825.
18. ☒ A second copy of the published international application under 35 U.S.C. 154(d)(4).
19. ☐ A second copy of the English language translation of the international application under 35 U.S.C. 154(d)(4).
20. ☒ Other items or information:
    PCT/IB/308 Form "Notice Informing the Applicant of the Communication of the Int'l Appl. to the Designated Offices"
    PCT/IPEA/416 Form "Notification of Transmittal of the Int'l Preliminary Examination Report"
    PCT/IPEA/409 Form "International Preliminary Examination Report

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U.S. APPLICATION NO. (if known, see 37 CFR 1.5)	INTERNATIONAL APPLICATION NO	ATTORNEY'S DOCKET NUMBER
09/936863	PCT/GB00/01074	US57.0326-WO

21. ☒ The following fees are submitted:

BASIC NATIONAL FEE (37 CFR 1.492 (a) (1) - (5)):

	CALCULATIONS	PTO USE ONLY
Neither international preliminary examination fee (37 CFR 1.482) nor international search fee (37 CFR 1.445(a)(2) paid to USPTO and International Search Report not prepared by the EPO or JPO **$1000.00**		
International preliminary examination fee (37 CFR 1.482) not paid to USPTO but International Search Report prepared by the EPO or JPO........... **$860.00**		
International preliminary examination fee (37 CFR 1.482) not paid to USPTO but international search fee (37 CFR 1.445(a)(2)) paid to USPTO **$710.00**		
International preliminary examination fee (37 CFR 1.482) paid to USPTO but all claims did not satisfy provisions of PCT Article 33(1)-(4)................... **$690.00**		
International preliminary examination fee (37 CFR 1.482) paid to USPTO and all claims satisfied provisions of PCT Article 33(1)-(4)........................... **$100.00**		
ENTER APPROPRIATE BASIC FEE AMOUNT =	$860.00	
Surcharge of **$130.00** for furnishing the oath or declaration later than ☐ 20 ☒ 30 months from the earliest claimed priority date (37 CFR 1.492(e)).	$130.00	

CLAIMS	NUMBER FILED	NUMBER EXTRA	RATE		
Total claims	29 - 20 =	9	x **$18.00**	$162.00	
Independent claims	4 - 3 =	1	x **$80.00**	$80.00	
MULTIPLE DEPENDENT CLAIM(S) (if applicable)			+ **$270.00**	$	
TOTAL OF ABOVE CALCULATIONS =				$	
☐ Applicant claims small entity status. See 37 CFR 1.27. The fees indicated above are reduced by 1/2. +				$	
SUBTOTAL =				$1232.00	
Processing fee of **$130.00** for furnishing the English translation later than ☐ 20 ☐ 30 months from the earliest claimed priority date (37 CFR 1.492(f)).				$	
TOTAL NATIONAL FEE =				$1232.00	
Fee for recording the enclosed assignment (37 CFR 1.21(h)). The assignment must be accompanied by an appropriate cover sheet (37 CFR 3.28, 3.31). **$40.00** per property +				$	
TOTAL FEES ENCLOSED =				$1232.00	
				Amount to be refunded:	$
				charged	**$1232.00**

a. ☐ A check in the amount of $____________ to cover the above fees is enclosed.

b. ☒ Please charge my Deposit Account No. **19-0615** in the amount of **$1232.00** to cover the above fees. A duplicate copy of this sheet is enclosed.

c. ☒ The Commissioner is hereby authorized to charge any additional fees which may be required, or credit any overpayment to Deposit Account No. **19-0615**. A duplicate copy of this sheet is enclosed.

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NOTE: Where an appropriate time limit under 37 CFR 1.494 or 1.495 has not been met, a petition to revive (37 CFR 1.137 (a) or (b)) must be filed and granted to restore the application to pending status.

SEND ALL CORRESPONDENCE TO:

Intellectual Property Law Department
Schlumberger-Doll Research
Old Quarry Road
Ridgefield, Connecticut 06877-4108
(203) 431-5506
September 17, 2001

[signature]
SIGNATURE

William B. Batzer
NAME

37,088
REGISTRATION NUMBER

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JC16 Rec'd PCT/PTO SEP 1 8 2001

Method and System For Reducing Effects of Sea Surface Ghost Contamination In Seismic Data

FIELD OF THE INVENTION:

The present invention relates to the field of reducing the effects of sea-surface ghost reflections in seismic data. In particular, the invention relates an improved de-ghosting method that utilises measurements or estimates of multi-component marine seismic data recorded in a fluid medium.

BACKGROUND OF THE INVENTION:

Removing the ghost reflections from seismic data is for many experimental configurations equivalent to up/down wavefield separation of the recorded data. In such configurations the down-going part of the wavefield represents the ghost and the up-going wavefield represents the desired signal. Exact filters for up/down separation of multi-component wavefield measurements in Ocean Bottom Cable (OBC) configurations have been derived by Amundsen and Ikelle, and are described in U.K. Patent Application Number 9800741.2. An example of such a filter corresponding to de-ghosting of pressure data at a frequency of 50 Hz for a seafloor with P-velocity of 2000 m/s, S-velocity of 500 m/s and density of 1800 kg/m3 is shown in Figure 2. At this frequency, the maximum horizontal wavenumber for P-waves right below the seafloor is $k=0.157\ m^{-1}$, whereas it is $k=0.628\ m^{-1}$ for S-waves. Notice the pole and the kink due to a zero in the filter at these two wavenumbers, making approximations necessary for robust filter implementations. Figure 3 shows approximations to the filter. These filters

are only good at wavenumbers smaller than the wavenumber where the pole occurs. Hence, energy with low apparent velocities (for instance S-waves or Scholte waves at the seafloor) will not be treated properly. Moreover, since they do not have a complex part, evanescent waves will also not be treated properly.

The OBC de-ghosting filters have been shown to work very well on synthetic data. However, apart from the difficulty with poles and zeros at critical wave numbers, they also require knowledge about the properties of the immediate sub-bottom locations as well as hydrophone/geophone calibration and coupling compensation.

A normal incidence approximation to the de-ghosting filters for data acquired at the sea floor was described by Barr, F.J. in U.S. Patent: 4,979,150, issued 1990, entitled 'System for attenuating water-column reflections', (hereinafter "Barr (1990)"). For all practical purposes, this was previously described by White, J.E., in a 1965 article entitled 'Seismic waves: radiation, transmission and attenuation', McGraw-Hill (hereinafter "White (1965)"). However, this technique is not effective when the angle of incidence is away from vertical. Also, this technique does not completely correct for wide-angle scattering and the complex reflections from rough sea surfaces. Additionally, its is believed that the OBC techniques described have not been used successfully in a fluid medium, such as with data gathered with towed streamers.

SUMMARY OF THE INVENTION:

Thus, it is an object of the present invention to provide a method of de-ghosting which improves attenuation of noise from substantially all non-horizontal angles of incidence.

It is an object of the present invention to provide a method of de-ghosting of seismic measurements made in a fluid medium which improves attenuation of the ghost as well as downward propagating noise from substantially all non-horizontal angles of incidence.

Also, it is an object of the present invention to provide a method of de-ghosting which is not critically dependent on knowledge about the properties of the surrounding fluid medium as well as hydrophone/geophone calibration and coupling compensation.

Also, it is an object of the present invention to provide a method of de-ghosting whose exact implementation is robust and can be implemented efficiently.

According to the invention, a method is described for sea surface ghost correction through the application of spatial filters to the case of marine seismic data acquired in a fluid medium. Using, for example, either typical towed streamer or vertical cable geometries. Preferably, both pressure and vertical velocity measurements are acquired along the streamer. The invention takes advantage of non-conventional velocity measurements taken along a marine towed streamer, for example. New streamer designs are currently under development and are expected to become commercially available in the near future. For example, the Defence Evaluation and Research Agency (DERA), based in

Dorset, U.K., claim to have successfully built such a streamer for high frequency sonar applications.

According to an alternative embodiment, the invention is also applicable to seismic data obtained with configurations of multiple conventional streamers. Here, the filters make use of vertical pressure gradient measurements, as opposed to velocity measurements. According to the invention, an estimate of the vertical pressure gradient can be obtained from over/under twin streamer data, or more generally from streamer data acquired by a plurality of streamers where the streamers are spatially deployed in a manner analogous to that described in U.K Patent Application Number 9820049.6, by Robertsson, entitled 'Seismic detection apparatus and related method" filed in 1998 (hereinafter "Robertsson (1998)"). For example, three streamers can be used, forming a triangular shape cross-section along their length. Vertical pressure gradient data can also be obtained from pressure gradient measuring devices.

According to the invention, the filters fully account for the rough sea perturbed ghost, showing improvement over other techniques based on normal incidence approximations (see e.g., White (1965)), which have been applied to data recorded at the sea floor.

Advantageously, according to preferred embodiments of the invention, the results are not sensitive to streamer depth, allowing the streamer(s) to be towed at depths below swell noise contamination, hence opening up the acquisition weather window where shallow towed streamer data would be unusable. Local streamer accelerations will be minimised in the deep water flow regime, improving resolution of the

pressure, multi-component velocity and pressure gradient measurements.

Advantageously, according to preferred embodiments of the invention, there are no filter poles in the data window, except for seismic energy propagating horizontally at the compressional wave speed in water.

Advantageously, according to preferred embodiments of the invention, the filter is not critically dependent on detailed knowledge of the physical properties of the surrounding fluid medium.

The filters can be simple spatial convolutions, and with the regular geometry of typical towed streamer acquisition the filters are efficient to apply in the frequency-wavenumber (FK) domain. The filters can also be formulated for application in other domains, such as time-space and intercept time-slowness (τ-p).

According to the invention, a method of reducing the effects in seismic data of downward propagating reflected and scattered acoustic energy travelling in a fluid medium is provided. The method advantageously makes use of two types of data: pressure data, that represents the pressure in the fluid medium, such as sea water, at a number of locations; and vertical particle motion data, that represents the vertical particle motion of the acoustic energy propagating in the fluid medium at a number of locations within the same spatial area as the pressure data. The distance between the locations that are represented by the pressure data and the vertical particle motion data in each case is preferably less than the Nyquist spatial sampling criterion. The vertical particle motion data can

be in various forms, for example, velocity, pressure gradient, displacement, or acceleration.

The spatial filter is created by calculating a number of coefficients that are based on the velocity of sound in the fluid medium and the density of the fluid medium. The spatial filter is designed so as to be effective at separating up and down propagating acoustic energy over substantially the entire range of non-horizontal incidence angles in the fluid medium.

The spatial filter is applied to either the vertical particle motion data or to the pressure data, and then combined with the other data to generate pressure data that has its up and down propagating components separated. The separated data are then processed further and analysed. Ordinarily the down-going data would be analysed, but the up going data could be used instead if the sea surface was sufficiently calm.

According to an alternative embodiment, a method of reducing the effects of downward propagating reflected and scattered acoustic energy travelling in a fluid medium is provided wherein the pressure data and vertical particle motion data represent variations caused by a first source event and a second source event. The source events are preferably generated by firing a seismic source at different locations at different times, and the distance between the locations is preferably less than the Nyquist spatial sampling criterion.

The present invention is also embodied in a computer-readable medium which can be used for directing an apparatus, preferably a computer, to reduce the effects in seismic data of downward propagating reflected and scattered

acoustic energy travelling in a fluid medium as otherwise described herein.

BRIEF DESCRIPTION OF THE DRAWINGS:

Figure 1 shows examples of simple seismic ray paths for primary events, and ghosts that are last reflected from the rough sea-surface;

Figure 2 shows an exact pressure de-ghosting filter for OBC data for a seafloor with P-velocity of 2000 m/s, S-velocity of 500 m/s and density of 1800 kg/m3; the upper panel shows the Real part of exact filter; and the lower panel shows the Imaginary part of exact filter;

Figure 3 shows the Real part of the exact OBC de-ghosting filter (in the solid line) shown in Figure 2, the first order Taylor approximation filter (in the plus line), and the first four fractional expansion approximations filters (in the dash-dotted lines);

Figure 4 illustrates the potential impact of 3D rough sea surface ghost reflection and scattering on consistency of the seismic data waveform;

Figure 5 illustrates the potential impact of the rough sea surface ghost perturbation on time-lapse seismic data quality;

Figures 6a-6f show various embodiments for data acquisition set-ups and streamer configurations according to preferred embodiments of the invention;

Figure 7 shows an exemplary two-dimensional spatial filter response (ω/k_z) for dx=6m;

Figure 8 is a flow chart illustrating some of the steps of the de-ghosting method for the combination of

pressure and vertical velocity data to achieve separated pressure data, according to a preferred embodiment of the invention;

Figure 9 schematically illustrates an example of a data processor that can be used to carry out preferred embodiments of the invention;

Figure 10 shows an example of a shot record computed below a 4m significant wave height (SWH) rough sea surface, the left panel shows pressure, and the right panel shows vertical velocity scaled by water density and the compressional wave speed in water;

Figure 11 illustrates de-ghosting results of the shot record in Figure 10, the left panel shows results using the vertical incidence approximation, and the right panel illustrates the exact solution;

Figure 12 illustrates an example of de-ghosting results in detail for a single trace at 330m offset corresponding to an arrival angle of about 37 degrees, the upper panel shows the vertical incidence approximation, and the lower panel shows the Exact solution; and

Figures 13a-b illustrate two possible examples of multi-component streamer design.

DETAILED DESCRIPTION OF THE INVENTION:

Figure 1 is a schematic diagram showing reflections between a sea surface (S), sea floor (W) and a target reflector (T). Various events that will be recorded in the seismogram are shown and are labelled according to the series of interfaces they are reflected at. The stars

indicate the seismic source and the arrowheads indicate the direction of propagation at the receiver. Events ending with 'S' were last reflected at the rough sea surface and are called receiver ghost events. Down-going sea-surface ghost reflections are an undesirable source of contamination, obscuring the interpretation of the desired up-going reflections from the earth's sub-surface.

Rough seas are a source of noise in seismic data. Aside from the often-observed swell noise, further errors are introduced into the reflection events by ghost reflection and scattering from the rough sea surface. The rough sea perturbed ghost events introduce errors that are significant for time-lapse seismic surveying and the reliable acquisition of repeatable data for stratigraphic inversion.

The effect of the rough sea is to perturb the amplitude and arrival time of the sea surface reflection ghost and add a scattering coda, or tail, to the ghost impulse. The impulse response can be calculated by finite difference or Kirchhoff methods (for example) from a scattering surface which represents statistically typical rough sea surfaces. For example, a directional form of the Pierson-Moskowitz spectrum described by Pierson, W.J. and Moskowitz, L., 1964 'A proposed Spectral Form for Fully Developed Wind Seas Based on the Similarity Theory of S. A. Kitaigorodskii' J. Geo. Res., 69, 24, 5181-5190, (hereinafter "Pierson and Moskowitz (1964)"), and Hasselmann, D. E., Dunckel, M. and Ewing, J.A., 1980 'Directional Wave Spectra Observed During JONSWAP 1973', J. Phys. Oceanography, v10, 1264-1280, (hereinafter "Hasselmann *et al*, (1980)"). Both the wind's speed and direction define

the spectra. The Significant Wave Height ("SWH") is the subjective peak to trough wave amplitude, and is about equal to 4 times the RMS wave height. Different realisations are obtained by multiplying the 2D surface spectrum by Gaussian random complex numbers.

Figure 4 shows an example of rough sea impulses along a 400m 2D line (e.g. streamer) computed under a 2m SWH 3D rough sea surface. The streamer shape affects the details of the impulses, and in this example the streamer is straight and horizontal. Figure 4 shows, from top to bottom: The ghost wavelet (white trough) arrival time, the ghost wavelet maximum amplitude, a section through the rough sea realisation above the streamer, and the computed rough sea impulses. The black peak is the upward travelling wave, which is unperturbed; the white trough is the sea ghost reflected from the rough sea surface. The latter part of the wavelet at each receiver is the scattering coda from increasingly more distant parts of the surface. Notice that the amplitude and arrival time ghost perturbations change fairly slowly with offset. The arrival time perturbations are governed by the dominant wavelengths in the sea surface, which are 100-200m for 2-4m SWH seas, and the amplitude perturbations are governed by the curvature of the sea surface which has an RMS radius of about 80m and is fairly independent of sea state. The diffraction coda appear as quasi-random noise following the ghost pulse.

The rough sea perturbations cause a partial fill and a shift of the ghost notch in the frequency domain. They also add a small ripple to the spectrum, which amounts to 1-2dB of error for typical sea states. In the post stack

domain this translates to an error in the signal that is about -20dB for a 2m SWH sea.

Figure 5 shows an example of how such an error can be significant for time-lapse surveys. The panel on the top left shows a post-stack time-migrated synthetic finite difference seismic section. The top middle panel shows the same data but after simulating production in the oil reservoir by shifting the oil water contact by 6m and introducing a 6m partial depletion zone above this. The small difference is just noticeable on the black leg of the reflection to the right of the fault just below 2s two-way travel-time. The panel on the right (top) shows the difference between these two sections multiplied by a factor of 10. This is the ideal seismic response from the time-lapse anomaly.

The left and middle bottom panels show the same seismic sections, but rough sea perturbations for a 2m SWH (as described above) have been added to the raw data before processing. Note that different rough sea effects are added to each model to represent the different seas at the time of acquisition. The difference obtained between the two sections is shown on the bottom right panel (again multiplied by a factor of 10). The errors in the reflector amplitude and phase (caused by the rough sea perturbations) introduce noise of similar amplitude to the true seismic time-lapse response. To a great extent, the true response is masked by these rough sea perturbations. A method for correcting these types of error is clearly important in such a case, and with the increasing requirement for higher quality, low noise-floor data, correction for the rough sea ghost becomes necessary even in modest sea states.

Equation (1) gives the frequency domain expression for a preferred filter relating the up-going pressure field, $p^u(x)$, to the total pressure, $p(x)$, and vertical particle velocity, $v_z(x)$.

$$p^u(x) = 0.5\left[p(x) + \frac{\rho\omega}{k_z} * v_z(x)\right] \qquad (1)$$

where k_z is the vertical wavenumber for compressional waves in the water, ρ is the density of water and * denotes spatial convolution.

The vertical wavenumber is calculated from $k_z^2=k^2-k_x^2$ for two-dimensional survey geometries, or $k_z^2=k^2-k_x^2-k_y^2$ for three-dimensional survey geometries, with $k^2=\omega^2/c^2$, where c is the compressional wave speed in the water and k_x is the horizontal wavenumber for compressional waves in the water. The regular sampling of typical towed streamer data allows k_z to be calculated efficiently in the FK domain. Figure 7 shows an example of the filter response, ω/k_z for dx=6m (the filter is normalised for the display to an arbitrary value). Infinite gain poles occur when k_z is zero. This corresponds to energy propagating horizontally (at the compressional wave speed in water). For towed streamer data, there is little signal energy with this apparent velocity, any noise present in the data with this apparent velocity should be filtered out prior to the filter application, or, the filter should be tapered at the poles prior to application to avoid amplification of the noise.

The traditional filter (White (1965), Barr, (1990)) is equation (2):

$$p^u = 0.5[p + \rho c\, v_z] \qquad (2)$$

By comparison to equation (1), we see that this is a normal incidence approximation, which occurs when k_x is zero. This is implemented as a simple scaling of the vertical velocity trace followed by its addition to the pressure trace.

Equation (1) can also be formulated in terms of the vertical pressure gradient (dp(x)/dz). The vertical pressure gradient is proportional to the vertical acceleration:

$$dp(x)/dz = \rho\, dv_z(x)/dt \qquad (3)$$

Integrating in the frequency domain through division of iω, and substituting in equation (1) gives:

$$p^u(x) = 0.5\left[p(x) + \frac{1}{ik_z} * dp(x)/dz\right] \qquad (4)$$

Figures 6a-6f show various embodiments for data acquisition set-ups and streamer configurations according to preferred embodiments of the invention. Figure 6a shows a seismic vessel 120 towing a seismic source 110 and a seismic streamer 118. The sea surface is shown by reference number 112. In this example, the depth of streamer 118 is about 60 meters, however those of skill in the art will recognise

that a much shallower depth would ordinarily be used such as 6-10 meters. The dashed arrows 122a-d show paths of seismic energy from source 110. Arrow 122a shows the initial down-going seismic energy. Arrow 122b shows a portion of the seismic energy that is transmitted through the sea floor 114. Arrow 122c shows an up-going reflection. Arrow 122d shows a down-going ghost reflected from the surface. According to the invention, the down-going rough sea receiver ghost 122d can be removed from the seismic data.

Figures 6b-6f show greater detail of acquisition set-ups and streamer configurations, according to the invention. Figure 6b shows a multi-component streamer 124. The streamer 124 comprises multiple hydrophones (measuring pressure) 126a, 126b, and 126c, and multiple 3C geophones (measuring particle velocity in three directions x, y, and z) 128a, 128b, and 128c. The spacing between the hydrophones 126a and 126b, and between geophones 128a and 128b is shown to be less than 12 meters. Additionally, the preferred spacing in relation to the frequencies of interest is discussed in greater detail below.

Figure 6c shows a streamer 130 that comprises multiple hyrdophones 132a, 132b, and 132c, and multiple pressure gradient measuring devices 134a, 134b, and 134c. The spacing between the hydrophones 132a and 132b, and between pressure gradient measuring devices 134a and 134b is shown to be less than 12 meters.

Figure 6d shows a multi-streamer configuration that comprises hydrophone streamers 140a and 140b. The streamers comprise multiple hyrdophones 142a, 142b, and 142c in the case of streamer 140a, and 142d, 142e, and 142f in the case of streamer 140b. The spacing between the

hydrophones is shown to be less than 12 meters. The separation between steamers 140a and 140b in the example shown in Figure 6d is less then 2 meters. Although the preferred separation is less than 2 meters, greater separations are contemplated as being within the scope of the invention. Figure 6e shows a cross sectional view of a dual streamer arrangement. Figure 6f shows a multi-streamer configuration comprising three hydrophone streamers 140a, 140b, and 140c.

Adequate spatial sampling of the wavefield is highly preferred for the successful application of the de-ghosting filters. For typical towed streamer marine data, a spatial sampling interval of 12m is adequate for all incidence angles. However, to accurately spatially sample all frequencies up to 125Hz (for all incidence angles), a spatial sampling interval of 6.25 meters is preferred. These spacings are determined according to the Nyquist spatial sampling criterion. Note that if all incidence angles are not required, a coarser spacing than described above can be used. The filters can be applied equally to both group formed or point receiver data.

Figure 8 is a flow chart illustrating some of the steps of the de-ghosting method for the combination of pressure and vertical velocity data to achieve separated pressure data, according to a preferred embodiment of the invention. In step 202, spatial filter coefficients are calculated. The coefficients are preferably dependent on the characteristics of the acquisition parameters 203 (such as the temporal sample interval of the pressure and particle motion data, the spatial separation of the vertical particle motion measuring devices, and the spatial aperture of the

filter), the density of the fluid medium 206, and the speed of the compressional wave in the fluid medium (or velocity of sound) 204. Vertical particle motion data 208 and pressure data 212 are received, typically stored as time domain traces on a magnetic tape or disk. In step 210, the vertical particle motion data 208 are convolved in with the spatial filter to yield filtered vertical particle motion data. In step 214 the filtered vertical particle motion data are added to pressure data 212 to give the downward propagating component of the separated pressure data. Alternatively, in step 216 the filtered vertical particle motion data are subtracted from pressure data 212 to give the upward propagating component of the separated pressure data. Finally, in step 218 the upward component is further processes and analysed.

The processing described herein is preferably performed on a data processor configured to process large amounts of data. For example, Figure 9 illustrates one possible configuration for such a data processor. The data processor typically consists of one or more central processing units 350, main memory 352, communications or I/O modules 354, graphics devices 356, a floating point accelerator 358, and mass storage devices such as tapes and discs 360. It will be understood by those skilled in the art that tapes and discs 360 are computer-readable media that can contain programs used to direct the data processor to carry out the processing described herein.

Figure 10 shows a shot record example, computed under a 4m Significant Wave Height (SWH) sea and using the finite-difference method described by Robertsson, J.O.A., Blanch, J.O. and Symes, W.W., 1994 'Viscoelastic finite-

difference modelling' Geophysics, 59, 1444-1456 (hereinafter "Robertsson *et al.* (1994)") and Robertsson, J.O.A., 1996 'A Numerical Free-Surface Condition for Elastic/Viscoelastic Finite-difference modelling in the Presence of Topography', *Geophysics, 61, 6, 1921-1934* (hereinafter "Robertsson (1996)"). The streamer depth in this example is 60m. The left panel shows the pressure response and the right panel shows the vertical velocity response scaled by the water density and the compressional wave speed in water. A point source 50Hz Ricker wavelet was used and the streamer depth was 60m in this example. The choice of streamer depth allows a clear separation of the downward travelling ghost from the upward travelling reflection energy for visual clarity of the de-ghosting results. The trace spacing on the plot is 24m. A single reflection and its associated ghost are shown, along with the direct wave travelling in the water layer. Perturbations in the ghost wavelet and scattering noise from the rough sea surface are evident.

Figure 11 shows the results of de-ghosting the shot record shown in Figure 10. The left panel shows the result using the normal incidence approximation and the right panel shows the result using the exact solution. The exact solution shows a consistent response over all offsets, whereas the normal incidence approximation starts to break down at incident angles greater than about 20 degrees, and shows a poorer result at the near offsets. Note that the direct wave is not amplified by the exact filter application even though the poles of the filter lie close to its apparent velocity. The exact filter is tapered before application such that it is has near unity response for frequencies and wavenumbers corresponding to apparent

velocities of 1500m/s and greater. The weak event just below the signal reflection is a reflection from the side absorbing boundary of the model. It is upward travelling and hence untouched by the filter.

Figure 12 shows details of the de-ghosted results for a single trace from Figure 11. The trace offset is 330m corresponding to a 37 degree incidence angle. The upper panel shows the normal incidence approximation, and the lower panel shows the exact solution. Not only does the exact solution provide a superior result in terms of the de-ghosting, but also in terms of amplitude preservation of the signal reflection - the upper panel shows loss of signal amplitude after the de-ghosting.

The filters described herein are applicable to, for example, measurements of both pressure and vertical velocity along the streamer. Currently, however, only pressure measurements are commercially available. Therefore, engineering of streamer sections that are capable of commercially measuring vertical velocity is preferred in order to implement the filters.

Figures 13a-b illustrate two possible examples of multi-component streamer design. Figure 13a shows a coincident pressure and single 3-component geophone. In this design, the 3-component geophone is perfectly decoupled from the streamer. Figure 13b shows a coincident pressure and twin 3-component geophones. In this design, one of the 3-component geophones is decoupled from the streamer, the other is coupled to the streamer; measurements from both are combined to remove streamer motion from the data.

In an alternative formulation, the filters make use of vertical pressure gradient measurements. An estimate

of vertical pressure gradient can be obtained from over/under twin streamers (such as shown in Figures 6d and 6e) and multiple streamers (such as shown in Figure 6f) deployed in configurations analogous to that described in Robertsson (1998), allowing the filters to be directly applied to such data. However, for the results to remain sufficiently accurate, the streamers should not be vertically separated by more than 2m for seismic frequencies below approximately 80Hz.

An important advantage of multiple streamer configurations such as shown in Figure 6f is that their relative locations are less crucial than for over/under twin streamer geometries, where the two streamers are preferably directly above one another.

The filters described here are applied in 2D (along the streamer) to data modelled in 2D. The application to towed streamer configurations naturally lends itself to this implementation, the cross-line (streamer) sampling of the wavefield being usually insufficient for a full 3D implementation. Application of these filters to real data (with ghost reflections from 3D sea surfaces) will give rise to residual errors caused by scattering of the wavefield from the cross-line direction. This error increases with frequency though is less than 0.5dB in amplitude and 3.6° in phase for frequencies up to 150Hz, for a 4m SWH sea. These small residual noise levels are acceptable when time-lapse seismic surveys are to be conducted.

Invoking the principle of reciprocity, the filters can be applied in the common receiver domain to remove the downward travelling source ghost. Reciprocity simply means

that the locations of source and receiver pairs can be interchanged,(the ray path remaining the same) without altering the seismic response. Figure 1 can also be used to define the source ghost if the stars are now regarded as receivers and the direction of the arrows is reversed, with the source now being located at the arrow. This application is particularly relevant for data acquired using vertical cables, which may be tethered, for example, to the sea floor, or suspended from buoys. In the case of Figure 6a, those of skill in the art will understand that as the seismic vessel 120 travels though the water, the firing position of source 110 will change. The different positions of source 110 can be then be used to construct data in the common receiver domain as is well known in the art.

While preferred embodiments of the invention have been described, the descriptions and figures are merely illustrative and are not intended to limit the present invention.

CLAIMS

What is claimed is:

1. A method of reducing the effects in seismic data of downward propagating reflected and scattered acoustic energy travelling in a fluid medium comprising the steps of:

receiving pressure data representing at least the pressure in the fluid medium at a first location and a second location, the first location being in close proximity to the second location;

receiving vertical particle motion data representing at least the vertical particle motion of acoustic energy propagating in the fluid medium at a third location and a fourth location, the third location being in close proximity to the fourth location, and the first, second, third and fourth locations being within a spatial area;

calculating a plurality of spatial filter coefficients based in part on the velocity of sound in the fluid medium, the density of the fluid medium and a plurality of acquisition parameters, thereby creating a spatial filter which is designed so as to be effective at separating up and down propagating acoustic energy over a range of non-vertical incidence angles in the fluid medium;

applying the spatial filter to the vertical particle motion data to generate filtered particle motion data;

combining the filtered particle motion data with the pressure data to generate separated pressure data, the separated pressure data having up and down propagating components separated; and

analysing at least part of the up or down propagating component of the separated pressure data.

2. The method of claim 1 wherein the acquisition parameters include the temporal sampling interval, the spatial sampling interval, and the number of independent locations at which the pressure and vertical particle motion data are measured.

3. The method of claim 1 wherein the vertical particle motion data is measured using one or more multi-component streamers.

4. The method of claim 1 wherein the vertical particle motion of the acoustic energy represented in said vertical particle motion data is the particle velocity of the acoustic energy.

5. The method of claim 1 wherein the vertical particle motion of the acoustic energy represented in said vertical particle motion data is the vertical pressure gradient of the acoustic energy.

6. The method of claim 5 wherein the pressure gradient is measured using at least two parallel streamer cables in close proximity and vertically offset from one another.

7. The method of claim 1 wherein the vertical particle motion of the acoustic energy represented in said vertical particle motion data is the vertical displacement of the acoustic energy.

8. The method of claim 1 wherein the vertical particle motion of the acoustic energy represented in said vertical particle motion data is the vertical acceleration of the acoustic energy.

9. The method of claim 1 wherein the distance between the first location and the second location and the distance between the third location and the fourth location is less than the Nyquist spatial sampling criterion.

10. The method of claim 9 wherein the spatial area is substantially a portion of a line, and the range of non-vertical incidence angles includes substantially all non-horizontal incidence angles within a vertical plane that passes through the portion of line.

11. The method of claim 9 wherein the spatial area is a portion of a substantially planar region, and the range of non-vertical incidence angles include substantially all non-horizontal incidence angles.

12. A method of reducing the effects in seismic data of downward propagating reflected and scattered

acoustic energy travelling in a fluid medium comprising the steps of:

receiving pressure data representing at least the pressure in the fluid medium at a first location and a second location, the first location being in close proximity to the second location;

receiving vertical particle motion data representing at least the vertical particle motion of acoustic energy propagating in the fluid medium at a third location and a fourth location, the third location being in close proximity to the fourth location, and the first, second, third and fourth locations being within a spatial area;

calculating a plurality of spatial filter coefficients based in part on the velocity of sound in the fluid medium and the density of the fluid medium, thereby creating a spatial filter which is designed so as to be effective at separating up and down propagating acoustic energy over a range of non-horizontal incidence angles in the fluid medium;

applying the spatial filter to the pressure data to generate filtered pressure data;

combining the filtered pressure data with the vertical particle motion data to generate separated pressure data, the separated pressure data having up and down propagating components separated; and

analysing at least part of the up or down propagating component of the separated pressure data.

13. The method of claim 12 wherein the distance between the first location and the second location and the distance between the third location and the fourth location is less than the Nyquist spatial sampling criterion.

14. The method of claim 12 wherein the vertical particle motion data is measured using one or more multi-component streamers.

15. The method of claim 12 wherein the vertical particle motion of the acoustic energy represented in said vertical particle motion data is the particle velocity of the acoustic energy.

16. The method of claim 12 wherein the vertical particle motion of the acoustic energy represented in said vertical particle motion data is the vertical pressure gradient of the acoustic energy.

17. The method of claim 16 wherein the pressure gradient is measured using at least two parallel streamer cables in close proximity and vertically offset from one another.

18. A method of reducing the effects in seismic data of downward propagating reflected and scattered acoustic energy travelling in a fluid medium comprising the steps of:

receiving pressure data representing at least variations in pressure in the fluid medium at a first location, the variations caused in part by a first

source event and a second source event, the first source event and the second source event being within a spatial area;

receiving vertical particle motion data representing at least the vertical particle motion of acoustic energy propagating in the fluid medium at a second location, the acoustic energy being caused in part by the first source event and the second source event;

calculating a plurality of spatial filter coefficients based in part on the velocity of sound in the fluid medium and the density of the fluid medium, thereby creating a spatial filter which is designed so as to be effective at separating up and down propagating acoustic energy from the first source event and second source event over a range of non-horizontal incidence angles in the fluid medium;

applying the spatial filter to the vertical particle motion data to generate filtered particle motion data;

combining the filtered particle motion data with the pressure data to generate separated pressure data, the separated pressure data having up and down propagating components separated; and

analysing at least part of the up or down propagating component of the separated pressure data.

19. The method of claim 18 wherein the first source event and the second source event are generated by firing a seismic source at different locations at different times, and the distance between the location of the first

source event and the location of the second source event is less than the Nyquist spatial sampling criterion.

20. The method of claim 18 wherein the vertical particle motion data is measured using one or more multi-component streamers.

21. The method of claim 18 wherein the vertical particle motion of the acoustic energy represented in said vertical particle motion data is the particle velocity of the acoustic energy.

22. The method of claim 18 wherein the vertical particle motion of the acoustic energy represented in said vertical particle motion data is the vertical pressure gradient of the acoustic energy.

23. The method of claim 22 wherein the pressure gradient is measured using at least two parallel streamer cables in close proximity and vertically offset from one another.

24. A computer-readable medium which can be used for directing an apparatus to reduce the effects in seismic data of downward propagating reflected and scattered acoustic energy travelling in a fluid medium comprising:

means for retrieving pressure data representing at least the pressure in the fluid medium at a first location and a second location, the first location being in close proximity to the second location;

means for retrieving vertical particle motion data representing at least the vertical particle motion of acoustic energy propagating in the fluid medium at a third location and a fourth location, the third location being in close proximity to the fourth location, and the first, second, third and fourth locations being within a spatial area;

means for calculating a plurality of spatial filter coefficients based in part on the velocity of sound in the fluid medium, the density of the fluid medium and a plurality of acquisition parameters, thereby creating a spatial filter which is designed so as to be effective at separating up and down propagating acoustic energy over a range of non-vertical incidence angles in the fluid medium;

means for applying the spatial filter to the vertical particle motion data to generate filtered particle motion data;

means for combining the filtered particle motion data with the pressure data to generate separated pressure data, the separated pressure data having up and down propagating components separated; and

means for analysing at least part of the up or down propagating component of the separated pressure data.

25. The computer-readable medium of claim 24 wherein the distance between the first location and the second location and the distance between the third location

and the fourth location is less than the Nyquist spatial sampling criterion.

26. The computer-readable medium of claim 24 wherein the vertical particle motion data is measured using one or more multi-component streamers.

27. The computer-readable medium of claim 24 wherein the vertical particle motion of the acoustic energy represented in said vertical particle motion data is the particle velocity of the acoustic energy.

28. The computer-readable medium of claim 24 wherein the vertical particle motion of the acoustic energy represented in said vertical particle motion data is the vertical pressure gradient of the acoustic energy.

29. The computer-readable medium of claim 28 wherein the pressure gradient is measured using at least two parallel streamer cables in close proximity and vertically offset from one another.

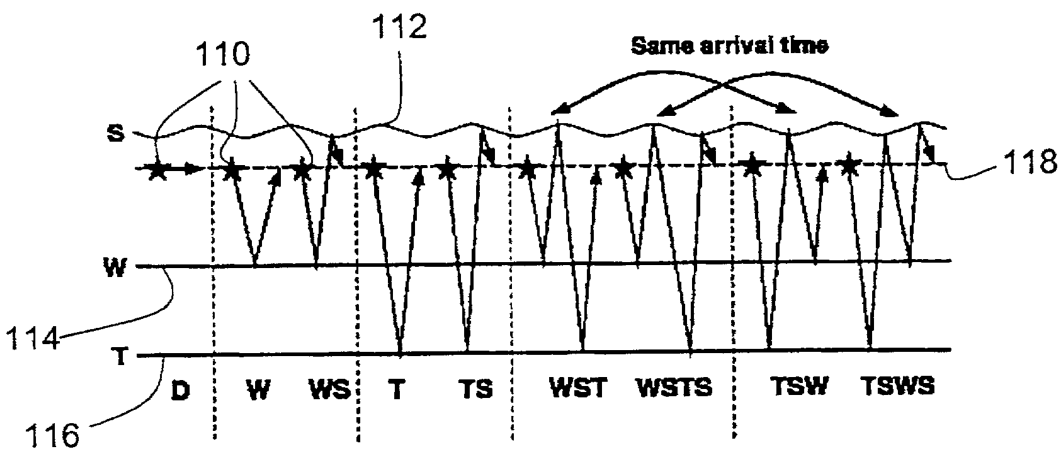
110
112
Same arrival time
S
118
W
114
T
116
D
W
WS
T
TS
WST
WSTS
TSW
TSWS

Figure 1

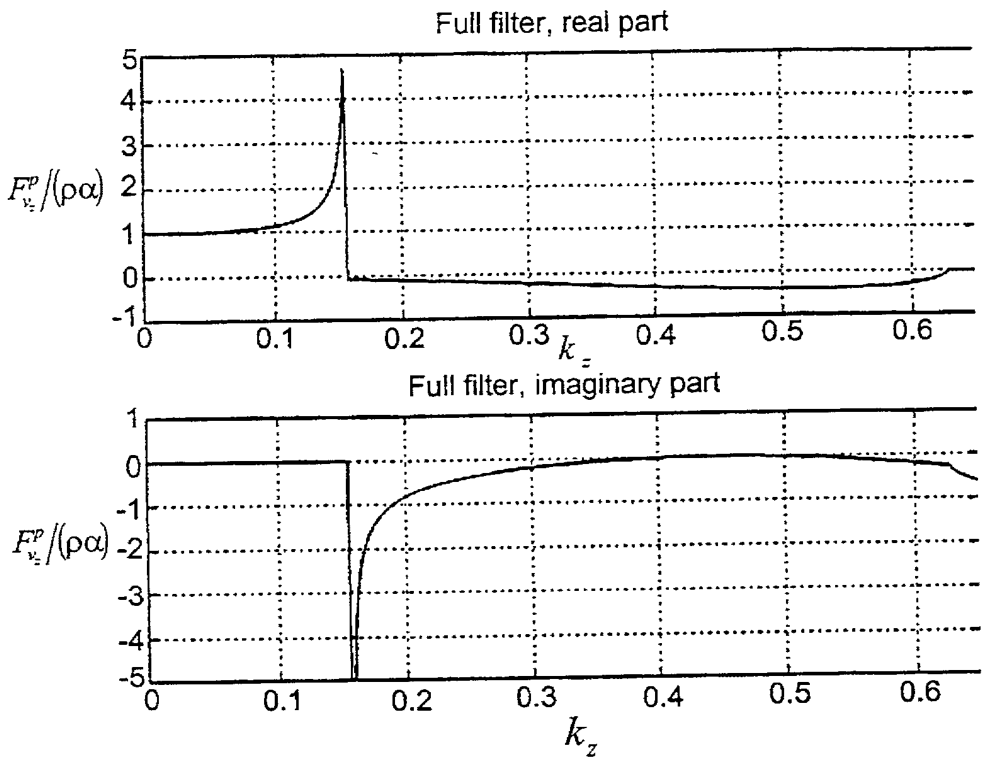

Figure 2 (prior art)

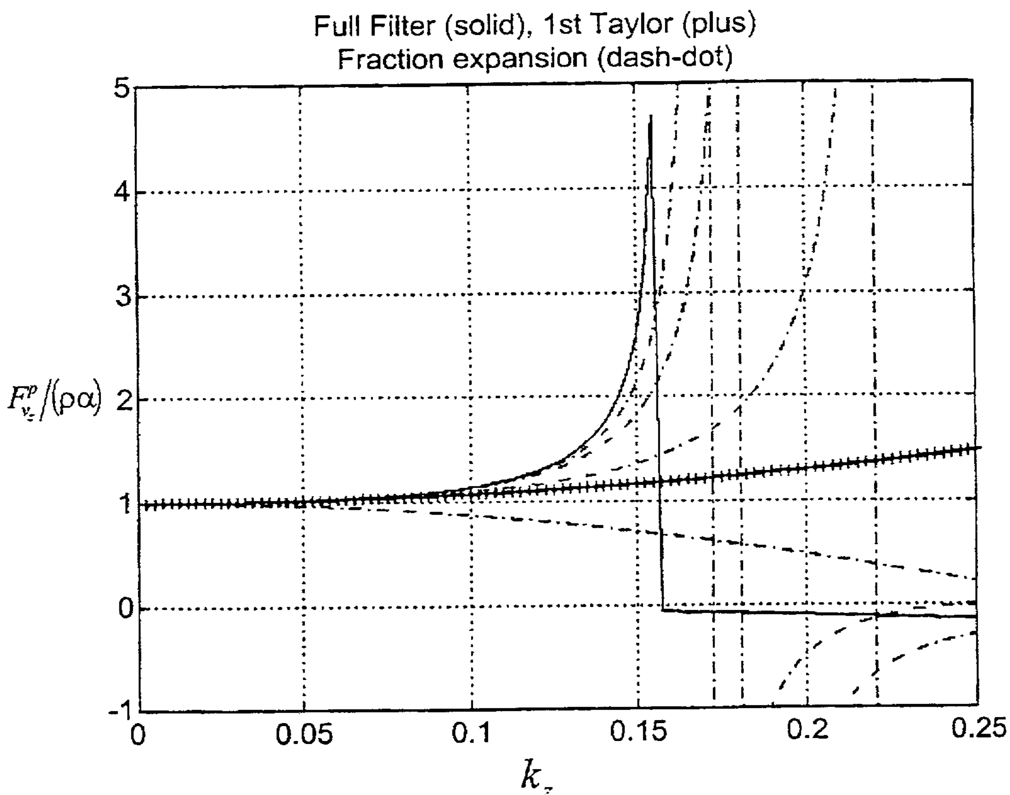

Figure 3 (prior art)

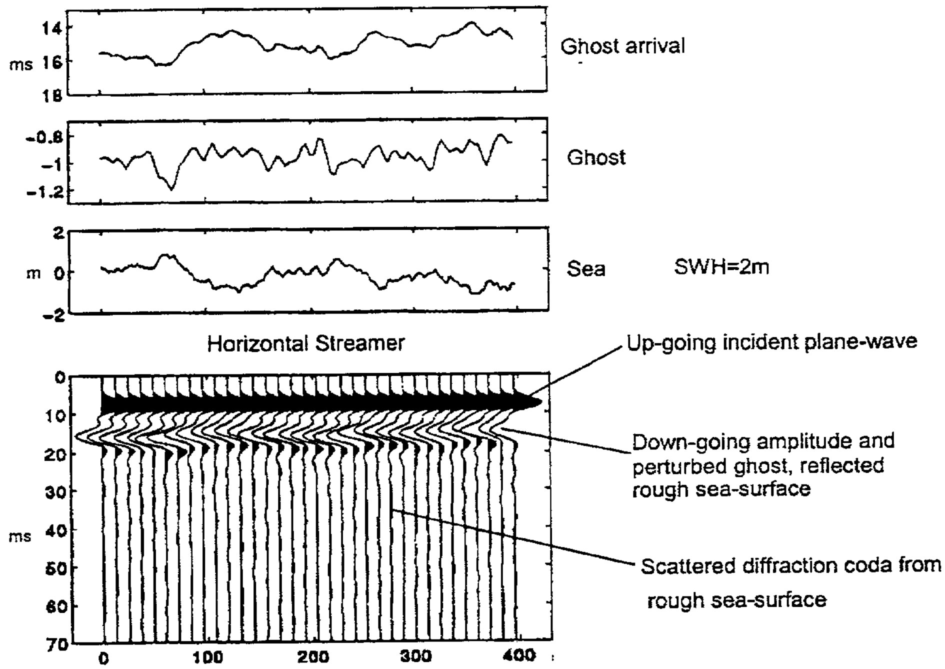
14
ms 16
18
Ghost arrival
-0.8
-1
-1.2
Ghost
2
m 0
-2
Sea
SWH=2m
Horizontal Streamer
Up-going incident plane-wave
0
10
20
30
ms 40
50
60
70
Down-going amplitude and perturbed ghost, reflected rough sea-surface
Scattered diffraction coda from rough sea-surface
0
100
200
300
400

Figure 4

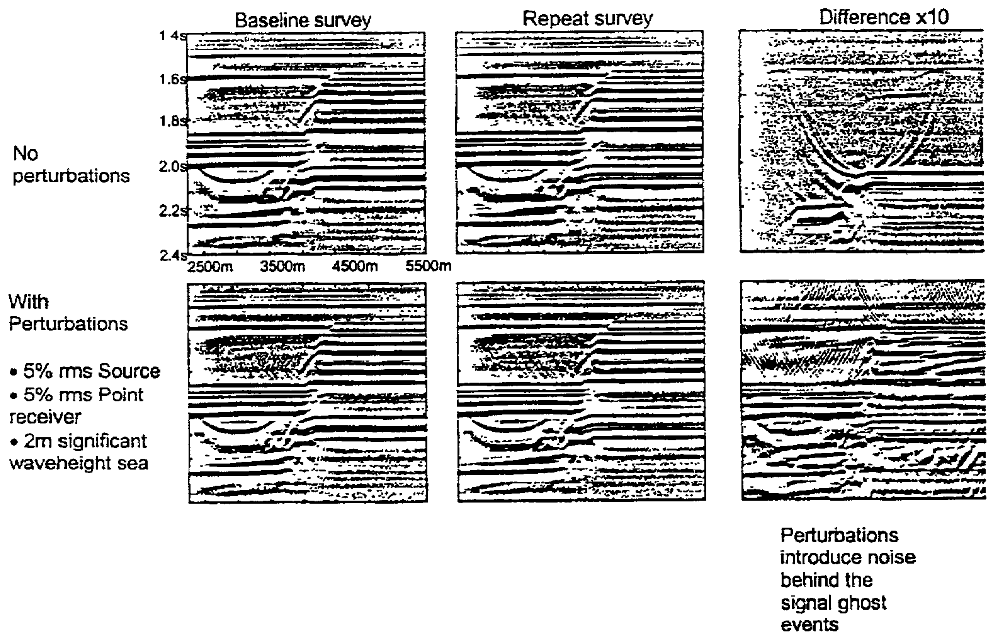
Baseline survey
Repeat survey
Difference x10
1.4s
1.6s
1.8s
2.0s
2.2s
2.4s
2500m
3500m
4500m
5500m
No
perturbations
With
Perturbations
• 5% rms Source
• 5% rms Point
receiver
• 2m significant
waveheight sea
Perturbations
introduce noise
behind the
signal ghost
events

Figure 5

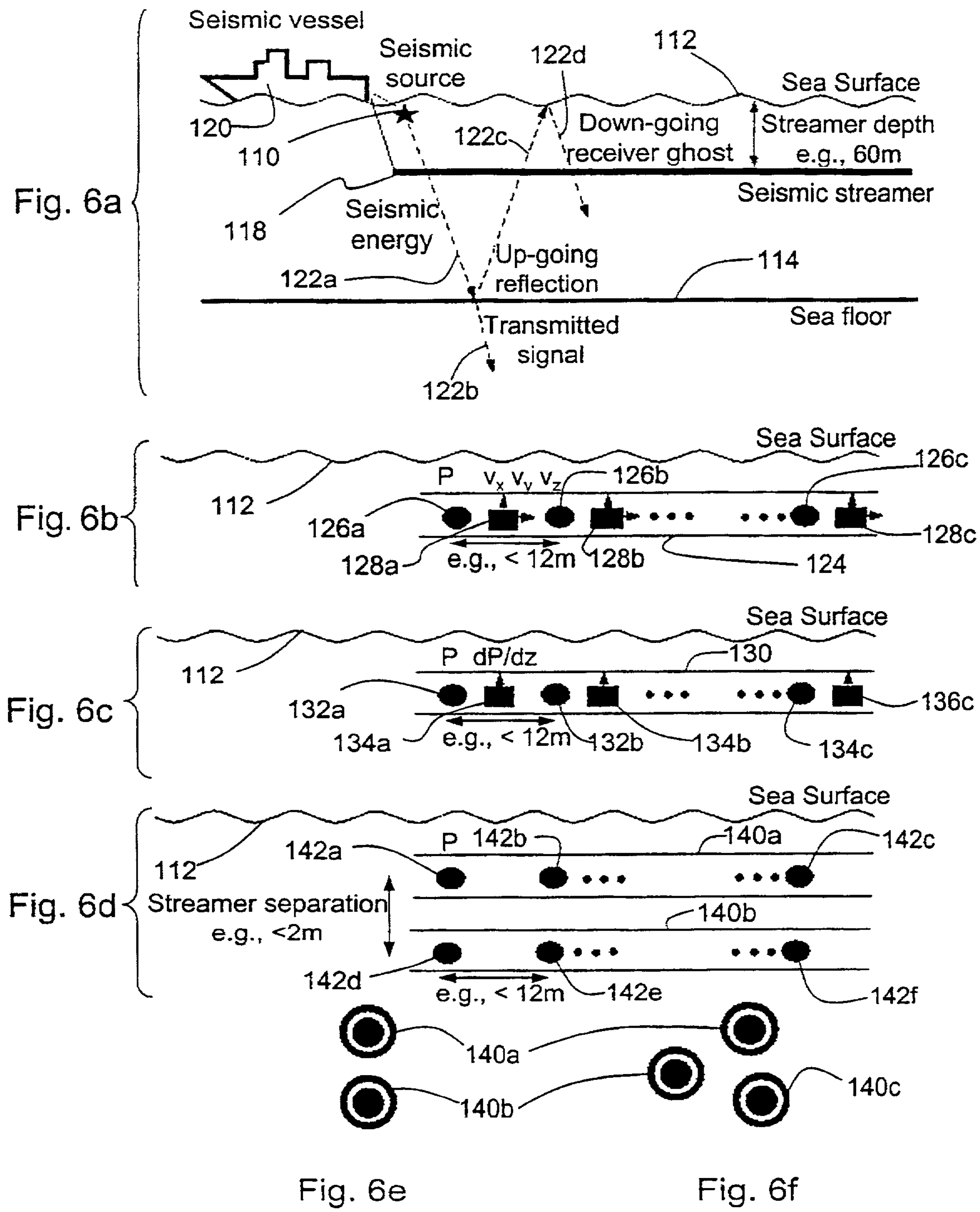
Fig. 6a
Seismic vessel
Seismic source
122d
112
Sea Surface
120
110
122c
Down-going receiver ghost
Streamer depth e.g., 60m
118
Seismic streamer
Seismic energy
Up-going reflection
114
122a
Sea floor
Transmitted signal
122b
Fig. 6b
Sea Surface
P v_x v_y v_z
126b
126c
112
126a
128c
128a
e.g., < 12m
128b
124
Fig. 6c
Sea Surface
P dP/dz
130
112
132a
136c
134a
e.g., < 12m
132b
134b
134c
Fig. 6d
Sea Surface
P 142b
140a
142c
142a
112
Streamer separation e.g., <2m
140b
142d
e.g., < 12m
142e
142f
140a
140b
140c
Fig. 6e
Fig. 6f

Figures 6a-f

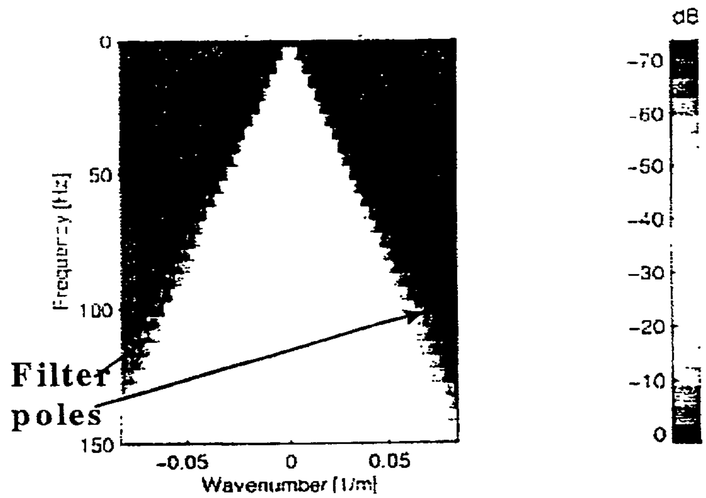
0
50
100
150
Frequency [Hz]
-0.05
0
0.05
Wavenumber [1/m]
Filter poles
dB
-70
-60
-50
-40
-30
-20
-10
0

Figure 7

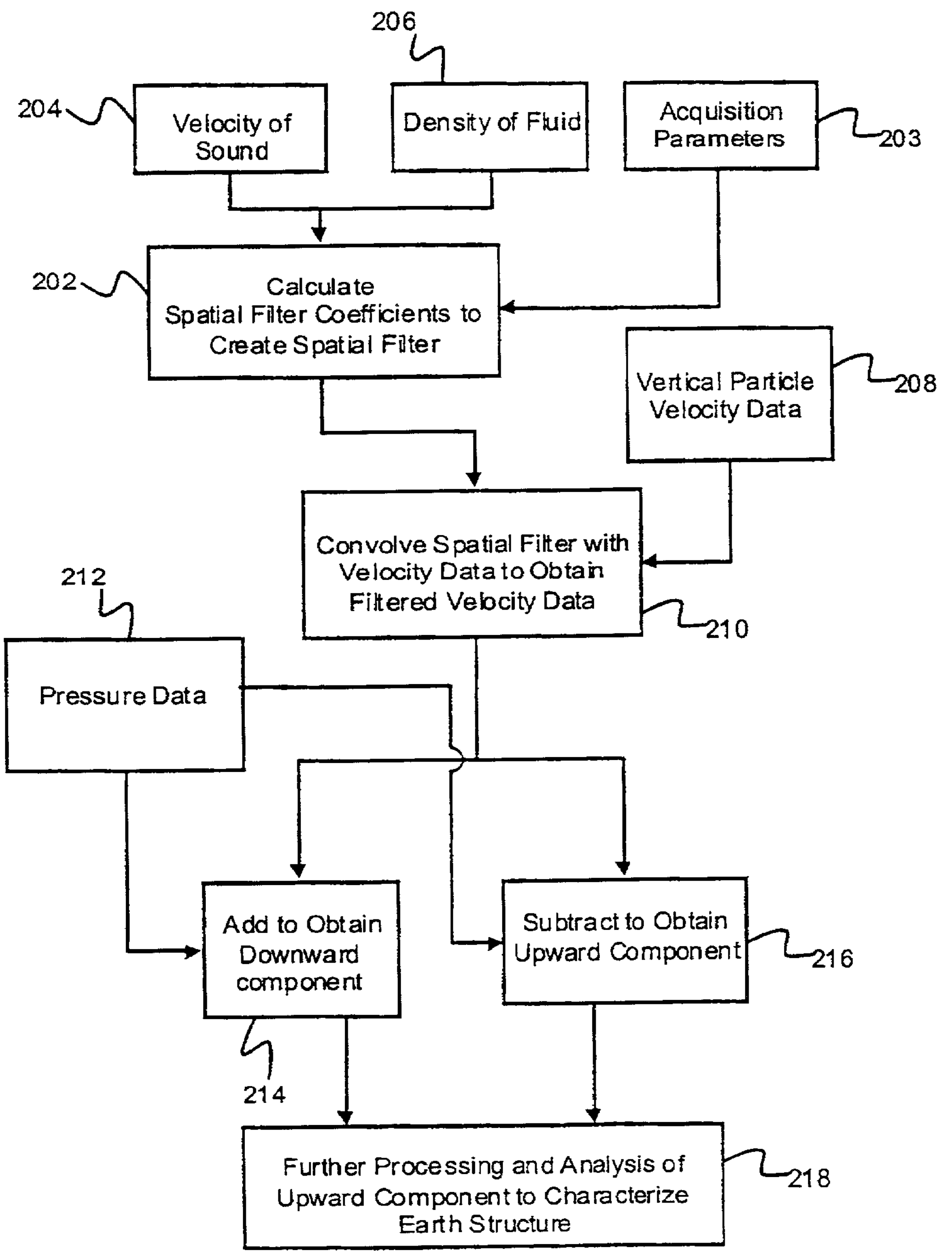
206
204
Velocity of Sound
Density of Fluid
Acquisition Parameters
203
202
Calculate Spatial Filter Coefficients to Create Spatial Filter
Vertical Particle Velocity Data
208
Convolve Spatial Filter with Velocity Data to Obtain Filtered Velocity Data
210
212
Pressure Data
Add to Obtain Downward component
Subtract to Obtain Upward Component
216
214
Further Processing and Analysis of Upward Component to Characterize Earth Structure
218

Figure 8

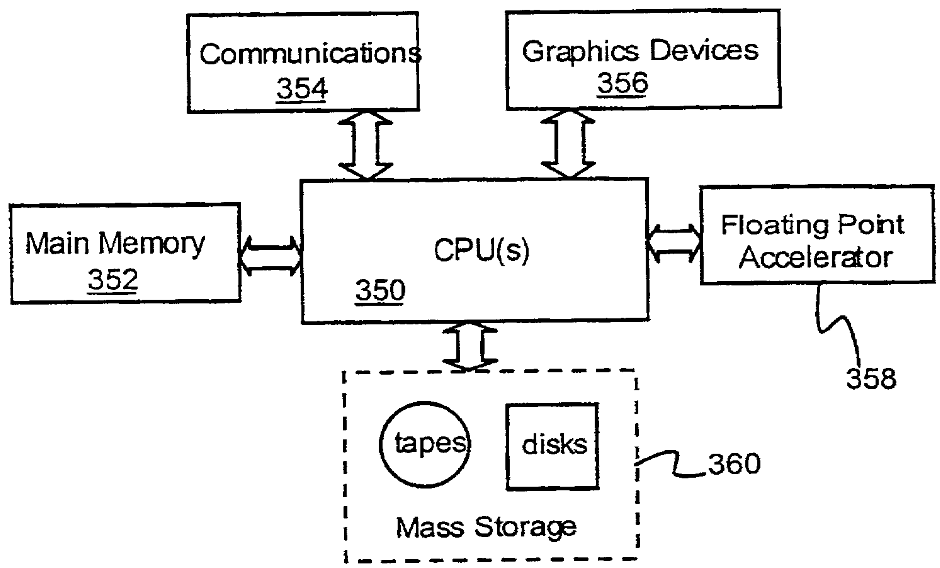
Communications
354
Graphics Devices
356
Main Memory
352
CPU(s)
350
Floating Point
Accelerator
358
tapes
disks
Mass Storage
360

Figure 9

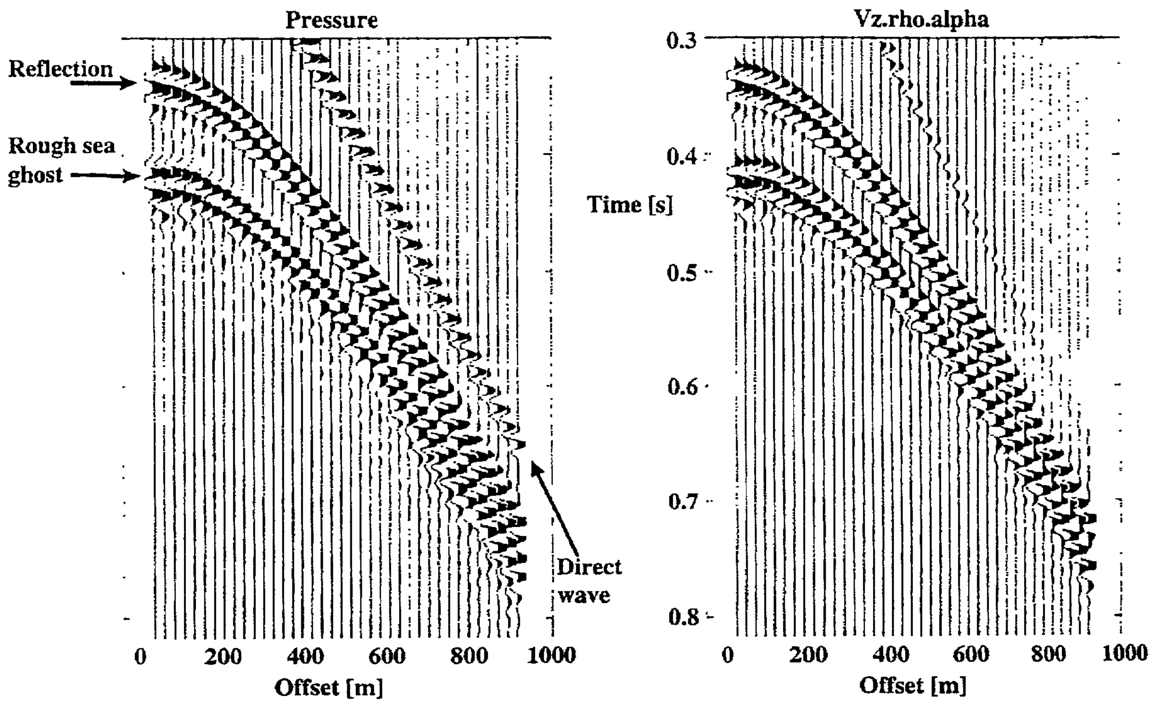
Pressure
Reflection
Rough sea ghost
Direct wave
0 200 400 600 800 1000
Offset [m]
Vz.rho.alpha
0.3
0.4
Time [s]
0.5
0.6
0.7
0.8
0 200 400 600 800 1000
Offset [m]

Figure 10

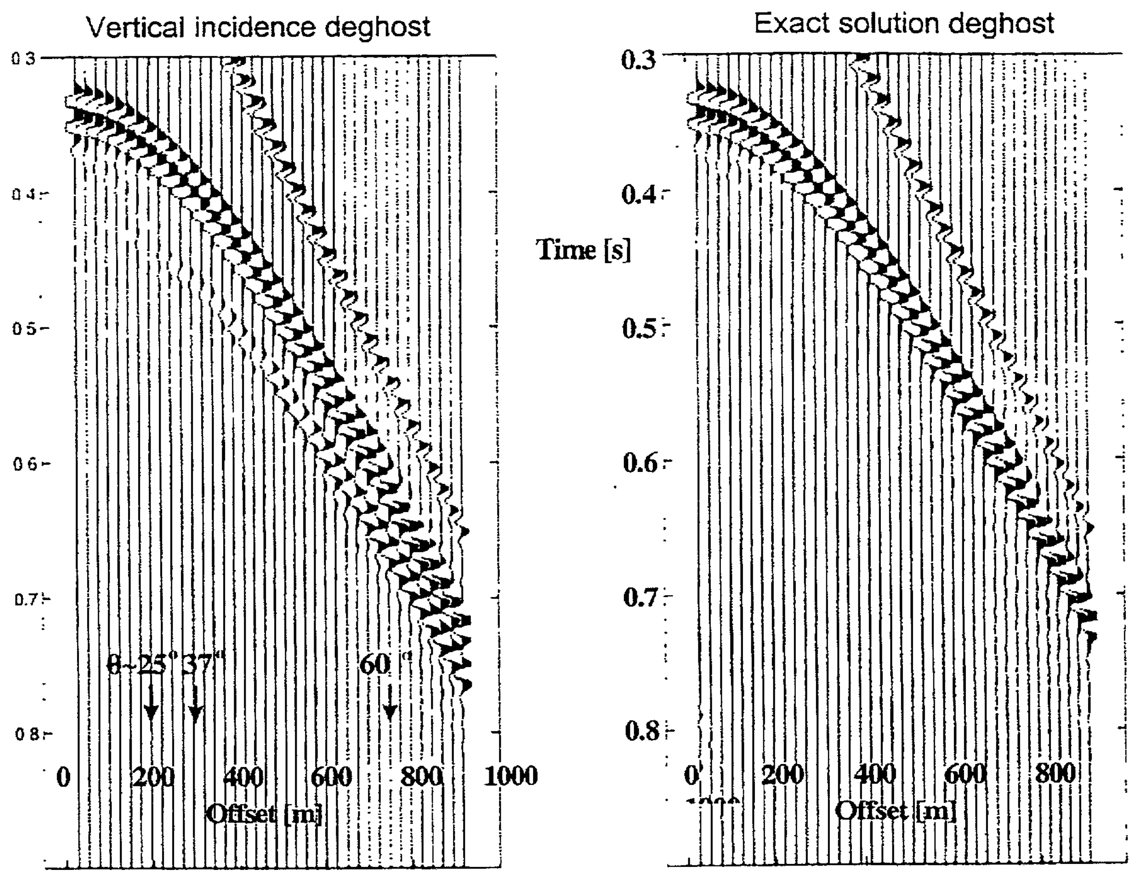
Vertical incidence deghost
Exact solution deghost
Time [s]
0.3
0.4
0.5
0.6
0.7
0.8
θ~25° 37°
60°
0
200
400
600
800
1000
Offset [m]

Figure 11

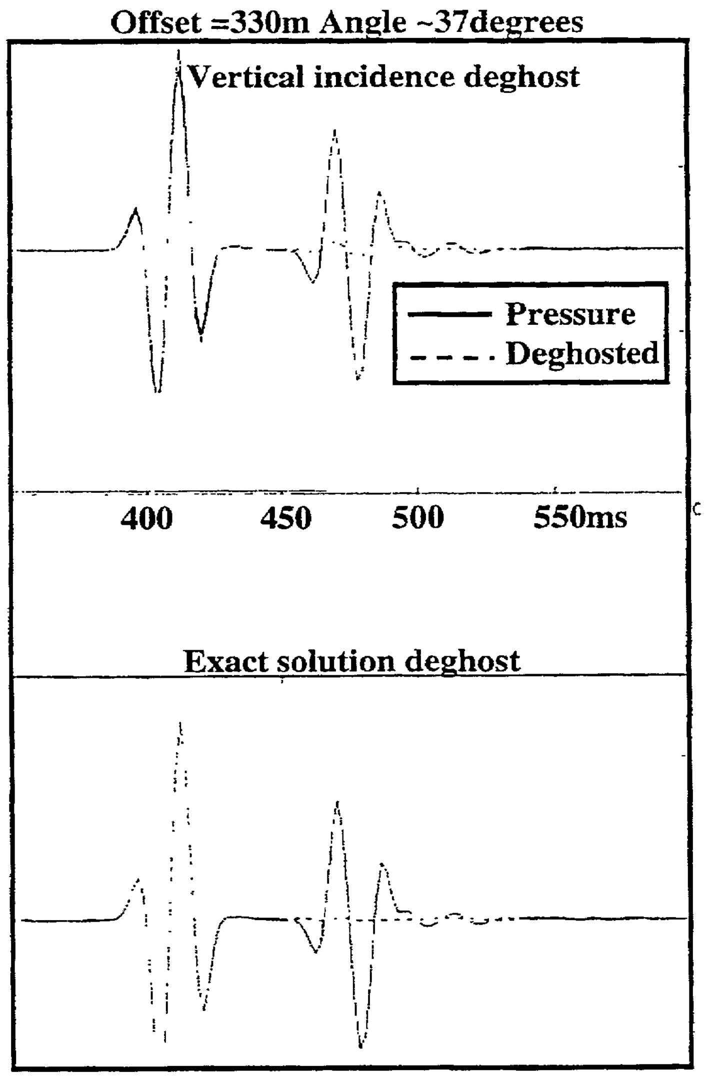
Offset =330m Angle ~37degrees
Vertical incidence deghost
Pressure
Deghosted
400
450
500
550ms
Exact solution deghost

Figure 12

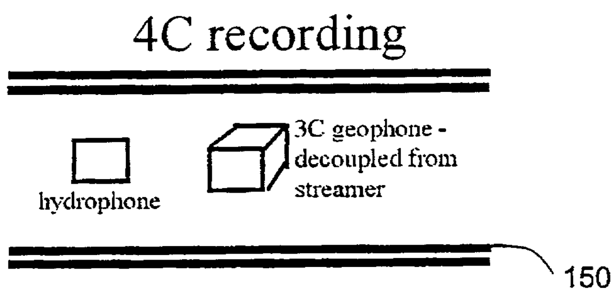

Figure 12a

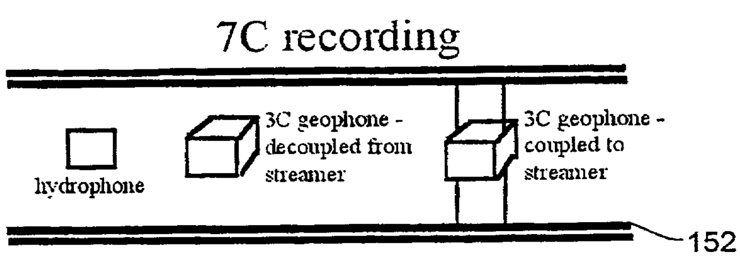

Figure 12b

DECLARATION FOR PATENT APPLICATION AND POWER OF ATTORNEY

As a below named inventor, I/We hereby declare that:

My/Our residence, post office address(s) and citizenship(s) are as stated below next to my/our name(s), and

I/We believe I/We am/are the original, first and sole inventor of the subject matter which is claimed (if only one name is listed below) or an original and first inventor of at least some of the subject matter which is claimed (if plural names are listed below) and for which a patent is sought on the invention entitled

METHOD AND SYSTEM FOR REDUCING EFFECTS OF SEA SURFACE GHOST CONTAMINATION IN SEISMIC DATA

the specification of which

☐ is attached hereto.

☒ was filed on 21 March 2000

as PCT International Application No. PCT/GB00/01074

and was amended on __________________ (if applicable).

I/We hereby state that I/we have reviewed and understand the contents of the above identified specification, including the claims, as amended by any amendment referred to above.

I/We acknowledge the duty to disclose information which is material to the examination of this application in accordance with Title 37, Code of Federal Regulations, Section 1.56(a).

Prior Foreign Application(s)

I/We hereby claim foreign priority benefits under Title 35, United States Code, Section 119 of any foreign application(s) for patent or inventor's certificate listed below and have also identified below any foreign application(s) for patent or inventor's certificate having a filing date before that of the application on which priority is claimed:

Country	Application No.	Filed (d/m/y)	Issued (d/m/y)	Priority Claimed
Great Britain	9906456.0	(22/03/99) 22 March 1999		Y ☒ N ☐

Prior United States Applications

I/We hereby claim the benefit under Title 35, United States Code, Section 120 of any United States application(s) listed below and, insofar as the subject matter of each of the claims of this application is not disclosed in the prior United States application in the manner provided by the first paragraph of Title 35, United States Code, Section 112, I/We acknowledge the duty to disclose material information as defined in Title 37, Code of Federal Regulations, Section 1.56(a) which occurred between the filing date of the prior application and the national or PCT international filing date of this application:

Application Serial No.	Filing Date (d/m/y)	Status (Patented, Pending, Abandoned)

And, I/We hereby appoint, both jointly and severally, as my attorney(s) and/or agent(s) with full power of substitution and revocation, to prosecute this application and to transact all business in the Patent and Trademark Office connected herewith the following attorney(s) and agent(s), their registration numbers being listed after their names.

4 John J. Ryberg, 31,134; William B. Batzer, 37,088; Erica W. Kuo, 42,775; and William L. Wang, 39,871

I/We hereby request that all correspondence be directed to:

Intellectual Property Law Department,
Schlumberger-Doll Research,
Old Quarry Rd., Ridgefield, CT 06877,
and that all telephone calls be directed to Patent Department at (203) 431-5507.

I hereby declare (if sole inventor) or each of us hereby declares (if joint inventors) that all statements made herein of my own knowledge are true and that all statements made on information and belief are believed to be true; and further that these statements were made with the knowledge that willful false statements and the like so made are punishable by fine or imprisonment, or both, under Section 1001 of Title 18 of the United States Code and that such willful false statements may jeopardize the validity of the application or any patent issuing thereon.

SOLE OR FIRST INVENTOR

Signature: John Robertsson Date: 25/9 -01

1-00 Full Name: Johan Olof Anders Robertsson

Residence: Stasjonsveien 28A, 0772 Oslo, Norway NOX

Citizenship: Sweden

Post Office Address: Stasjonsveien 28A, 0772 Oslo, Norway

SECOND INVENTOR

Signature: J E Kragh Date: 28-09-01

2-00 Full Name: Julian Edward Kragh

Residence: Sudbury Cottage, Cornish Hall End Road, Little Stampford, Essex CB10 2QS, United Kingdom GBX

Citizenship: United Kingdom

Post Office Address: Sudbury Cottage, Cornish Hall End Road, Little Stampford, Essex CB10 2QS, United Kingdom

3-00 **THIRD INVENTOR**

Signature: J.E. Martin Date: 25th Sept 2001

Full Name: James Edward Martin

Residence: Sandviksveien 93a, 1363 Høvik, Norway NOX

Citizenship: United Kingdom

Post Office Address: Sandviksveien 93a, 1363 Høvik, Norway

SCHLUMBERGER-DOLL RESEARCH
Old Quarry Road
Ridgefield, CT 06877-4108